Illinois Commerce Commission

Post-2006 Initiative

FINAL REPORT

RATES WORKING GROUP

I. Group Name – Rates Working Group

The Rates Working Group is referred to throughout this Report as the "RWG."

II. Group Administration

A. Participants List

The RWG enjoyed broad participation by all classes of affected and potentially-affected stakeholders, including the Staff of the Illinois Commerce Commission ("Staff"), Illinois electric utilities; affiliated and unaffiliated Alternative Retail Electric Suppliers ("ARES") and other competitive retail electric suppliers potentially interested in doing business in Illinois post-transition; PJM and MISO (Illinois' two Regional Transmission Organizations); representatives of residential, commercial, agricultural, educational, and industrial customers and customer groups, including CUB and the IIEC; state and municipal governments; independent generators; and environmental groups. Many of those stakeholders participated in all or nearly all of the RWG's meetings. Because the RWG identified the issues to be discussed in advance, other stakeholders were able to focus their participation on topics that were of particular interest to them or their constituencies.

Persons and organizations participating in the RWG include the following. A table identifying each individual participant by name and organization is attached as Appendix II-A.

Stakeholder Organizations†

Ameren Corporation and its Illinois operating utilities
Ameren Energy Marketing
Blue Star Energy
BOMA†
Business Energy Alliance & Resources, LLC
City of Chicago
Coalition of Energy Suppliers
ComEd
Community Energy Co-Op
Community Energy Cooperative
ConocoPhillips
Constellation New Energy
Cook County States Attorney
Corporate Concierge Services
Citizens' Utility Board (CUB)
Department of Commerce and Economic Opportunity (DCEO)
Direct Energy
Dynegy
Energy Connect Inc.
Environmental Law & Policy Center
Exelon Corporation
Foley & Lardner LLP
Giordano & Neilan, Ltd.
Illinois Commerce Commission – Commissioners' assistants and Staff
Illinois Attorney General
Illinois Industrial Energy Concumers (IIEC)
Illinois Power Company
KM Energy Consulting
Law Office of Michael A. Munson†
LeBoeuf, Lamb, Greene & MacRae LLP
Lt. Governor Pat Quinn's Office
M.C. Wilhelm Associates
MidAmerican Energy
Midwest Energy Alliance
Midwest Generation
MISO
Mt. Carmel Gas and Electric
Navitas
Peoples Energy Services
Piper Rudnick LLP

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PJM Interconnection, LLC
Reliant Energy
Shorenstein Realty Services
Solargenix Energy
Sonnenschein, Nath & Rosenthal
Strategic Energy
Trizec Properties, Inc.
U.S. Energy Savings
U.S. Department of Energy.
University of Illinois
URM
Zilkha Renewable Energy

Individual Participants[†]

Acevedo, Enver
Allen, Misty
Alongi, Larry
Alonso, Gabriel
Askounis, John
Baird, Mark
Barnabee, Margaret
Beyer, Gene
Borders, Will
Budd, Charley
Casey, Phillip
Casciani, Jennifer
Childress, Kris
Cohen, Martin
Cooper, Will
Crowell, Robert
Crumrine, Paul
DeBroff, Scott
Ericson, Christine
Favoriti, Dick
Fein, David
Fischer, Michael
Gale, Brent
Giordano, Patrick
Goldenberg, Allan
Gollomp, Lawrence
Graham, Angie
Griffin, Tom
Gudeman, Greg
Gutilla, Shauna
Hazlitt, Walter
Hedman, Susan
Hilton, B.J.
Huddleston, Barry N.P.
Ito, Wendy
Jolly, Ron
Jones, Chantal
Jones, Leonard
Juracek, Arlene
Kaminski, Mark
Kelly, Sharon
Knepler, Steve
Kolata, Dave
Kutsunis, Debbie
Lazare, Peter
Long, Dan
Lyson, Mercedes
Madiar, Eric
Maini, Kavita
Matchett, Barry
McDevitt, Daniel
McInerney, Tim
McNamara, Ron
Merchant, Heidi
Mill, Bob
Munson, Michael[†]
Norbeck, Michael
O'Connor, Phil
Pabian, Mike
Papadimitriu, Katie
Polidoro, Joe
Pollock, Jansen
Potts, Alan L.
Pusemp, Christina
Reddick, Conrad
Reed, Russell M.
Rippie, Glenn
Roberts, Courtney
Robertson, Eric
Robertson, Ryan
Satter, Susan L.
Scheu, Rachel
Selvaggio, Mary
Shea, Nick
Schlaf, Eric
Spear, Jerry
Slaby, Jeffrey T.
Spicuzza, Marie
Star, Anthony
Stephens, Bob
Strong, Michael
Townsend, Christopher
Voiles, Jackie
VonQualen, Janis
Walker-Ratliff, Joan
Warwick, Bill
Wernet, Debbie
Wilhelm, Martin
Wilson, Corey
Woodworth, Angela
Zarumba, Ralph[†]

[†] Individuals and entities marked with a "dagger" were participants during portions of the RWG process, but asked to withdraw prior to the issuance of this Final Report.

B. List of Meetings

1. Tuesday, May 4, 11:00 a.m., Chicago
2. Friday, May 21, 10:15 a.m., Chicago
3. Tuesday, June 1, 10:15 a.m., Chicago
4. Tuesday, June 8, 10:15 a.m., Chicago
5. Tuesday, June 15, 10:15 a.m., Chicago
6. Tuesday, June 22, 8:45 a.m., Chicago (Joint Meeting w/ other Procurement and Competitive Issues Working Groups)
7. Wednesday, June 23, 9:00 a.m., Chicago (Joint Meeting w/ other Procurement and Competitive Issues Working Groups)
8. Tuesday, June 29, 10:30 a.m., Chicago
9. Tuesday, July 13, 10:15 a.m., Chicago
10. Tuesday, July 20, 1:00 p.m., Chicago (Joint Meeting w/ other Procurement and Competitive Issues Working Groups)
11. Tuesday, July 27, 10:00 a.m., Springfield
12. Tuesday, August 3, 10:00 a.m., Springfield
13. Tuesday, August 10, 10:15 a.m., Chicago
14. Wednesday, August 18, 10:15 a.m., Chicago

III. Executive Summary

The RWG had considerable success in reaching consensus on a number of important rate and rate-related issues that will confront the State as the Mandatory Transition Period established by the 1997 Act comes to an end. Where consensus could not be reached on a single answer or in favor of a single policy, the RWG strove to identify the favored policy options, and to isolate the obstacles to complete consensus and the key issues that should guide the ultimate policy decision. Frequently, agreement was reached on that level even where agreement on a single consensus policy or answer could not be reached. The remainder of this Section identifies and summarizes major policy issues addressed by the RWG. For the complete text of the each agreement and consensus item, please see Section V of this report.

The RWG reached consensus that, when filing bundled service tariffs, utilities should separately determine the cost of the commodity component and provide unbundled price information to customers. In addition, the prices related to services which can be provided by a competitive Metering Service Provider should be unbundled even in tariffs where the services remain bundled. A single proceeding should be used by each utility to determine the unbundled delivery services rate and the distribution components of the bundled rates. Utilities should endeavor to synchronize the delivery charges in their unbundled rates with the delivery price components of their bundled rates. In addition, utilities should move towards synchronizing the bundled and unbundled customer classes.

The RWG reached consensus that utilities should at least partially hedge against variation in market prices included in the commodity portion of rates for residential and small commercial customers (as small commercial is defined in the Public Utilities Act ("PUA")). This hedging can be accomplished directly or through a procurement mechanism that hedges utility and customer risk. The costs of commodity acquisition, including the prudent and reasonable cost of associated hedging, should be included in the costs paid by customers using utility commodity services. Residential customers should be offered a stably-priced commodity service, and residential commodity prices, other than those contained in real time pricing ("RTP") tariffs, should be fixed for at least one monthly billing period. However, individual customers should be permitted to take service under a real time pricing rate. If a procurement plan to manage price risk is within the scope of the Commission's authority to review and pre-approve, and is in fact reviewed in advance and approved by the Commission as prudent, the prudence of the plan should not be re-examined after the fact. Nevertheless, an inquiry may be made after the fact as to whether, under a prudence or justness and reasonableness standard, the plan was followed, or whether it should be amended or terminated.

The RWG reached consensus that, under Scenario 1 ("Full Requirements Auction") and Scenario 2 ("Full Requirements RFP"), utilities should pass through, with no mark-ups or return on, the costs of acquiring the commodity itself. Under Scenario 3 ("Acquisition by Horizontal Tranche or Market Segment"), utilities' rates should include their costs of acquisition of the capacity and energy and the costs of hedging, if any. Under Scenario 4 ("Affiliate Purchases"), utilities' rates should include their costs of acquiring the capacity and energy and the costs of hedging, assuming that there is legally-sufficient evidence that no affiliate abuse has occurred.

Where the rates under Scenario 5 ("Market- or Cost-Index Approach') are based on an external benchmark, there is no role for post hoc regulatory review of the prudence of the Utilities' acquisition process, providing that the index has not been manipulated. As in Scenario 3, commodity acquisition costs of Scenario 6 ("Integrated Resource Planning") should be recovered. Under Scenario 7 ("Extension of the Transition Period"), utilities' should recover their commodity costs, in whole or in part, through existing, frozen bundled rates and through other rates that include commodity components at charges found to be just and reasonable by the Commission. Scenario 8 ("No Changes") embodies the idea that each utility remains free to propose different lawful acquisition processes and methods of reflecting commodity costs in their rates but that, regardless, the commodity component in rates should reflect the costs of acquisition. Under Scenario 9 ("Vertically Integrated Utility Supply") and Scenario 10 ("Re-Regulation of Electricity Production"), utilities will recover their production costs under traditional ratemaking principles or an alternative regulation structure, as allowed by law. Under Scenario 11 (originally defined as the "Texas Model", but revised before the Procurement Working Group and renamed the "Market-Responsive Pricing Model"), the utility, or preferably an affiliate, of the utility remains the default provider. Under this model, procurement would be done in accordance with the utility or its affiliate's credit policies/risk profile, with the default provider's shareholders bearing the supply risk, and retail prices charged by the provider are allowed to change with wholesale price changes. To the extent that the utility is generally relieved of the obligation and authority to provide retail bundled or unbundled commodity service, there will be no commodity costs for the it to recover. In regard to Scenario 12 ("Renewables"), any voluntary green pricing rate should allocate any incremental cost of required resources to the "green pricing" customers, not to other customers. If there is a general requirement to use renewable resources (*e.g.*, a Renewable Portfolio Standard), any incremental costs should be recoverable through rates, and if the requirement is applied equally to all suppliers, utility and competitive, such costs should be recovered through the commodity rate. The issue of renewable resources has also been discussed by the Competitive Issues Working Group ("CIWG"), the Procurement Working Group ("PWG"), and by the RWG in other contexts, as summarized below.

If the Commission assesses the prudence of a hedging plan retrospectively, the RWG reached consensus that it should apply traditionally-accepted prudence standards and rules of evidence. Where it is appropriate for the Commission to assess prudence prospectively or contemporaneously, the Commission should apply prudence standards to the process being used and the utilities' actions.

Under procurement Scenarios where the risks and costs of migration are built into the bid prices in an undifferentiated manner, retail customers should be able to come and go from the standard offer service, and the switching rules must be known by participants in, and be consistent with, the terms of any auction or RFP. However, under procurement Scenarios where the risks and the costs of migration are not built into the bid prices, returning customers may be expected to pay the incremental costs associated with their return to utility commodity service or to meet a minimum stay period coupled with a early termination fee. The RWG did not reach consensus as to whether delivery customers should also be liable for the potential costs incurred by utilities of hedging against their option to return before that option is exercised or if it is not exercised. Utilities should be able to recover the variable, and if any, fixed costs associated with offering "safety net" services to customers.

Assuming that the benefits exceed possible transaction and implementation costs, the efficient use of the commodity, and, in general, of generating and delivery resources as a whole is supported by the availability of rates for businesses and residential customers that reflect hourly real-time prices, ideally locationally. However, the RWG did not reach consensus as to whether hourly pricing rates must be offered by utilities to residential customers. Utilities should be allowed to implement and utilize voluntary programs to manage end use customer load to address constraints on the transmission or the utility's distribution systems.

The RWG reached consensus that properly designed interruptible, curtailable, and direct load control programs can promote efficiency of use by customers and can aid in optimizing the generation and delivery systems. The RWG reached consensus that, depending upon the utility's procurement circumstances and load characteristics, rate blocks can have a material effect on optimizing system efficiency, and that time of use and other pricing structures should provide sufficient incentive to encourage consumers to make energy demands more price-responsive. While the RWG did not reach consensus as to whether utilities should offer efficiency services, the RWG did reach consensus that utilities should not prohibit or unreasonably impede retail customers from participating in RTO programs for which they are eligible. In addition, providers in the competitive marketplace (Load Serving Entities and non-LSE Curtailment Service Providers) and RTOs may provide other types of incentives to encourage consumers to make energy demands more price responsive.

The net change (costs or savings), if any, in utility commodity acquisition costs resulting from energy efficiency and demand reduction programs should be fully included in commodity rates. The change in costs (whether an increase or decrease) of such programs in the utility's delivery expense or investment should be included in its delivery charges, and allocated to facility, customer and/or meter-related charges as appropriate. The RWG did not reach consensus as to the particular rate design appropriate for any particular program.

The RWG reached consensus that the question of whether a renewable portfolio standard ("RPS") should be mandated by Illinois after the end of the Mandatory Transition Period is an important issue and that there are considerations that must be reflected in a workable RPS, if one is mandated, including:

- Any RPS must be aligned with the post-2006 procurement process and facilitate the acquisition of cost-effective renewable energy.
- Any RPS must be competitively neutral and consistent with the consensus on RPS issues reached by the Competitive Issues Working Group.
- Any RPS must address cost recovery consistent with the consensus reached in the Rates Working Group.
- Any RPS must consider the effect of the use of renewable resources on rates.

There was disagreement, however, on whether or not an RPS should be mandated by the State of Illinois, and on whether other alternatives for stimulating cost-effective renewable resource development (*e.g.*, green rates) should be adopted. A number of participants supported or accepted an RPS adopted by the State, provided that certain conditions are met. These members expressed the views that Illinois has significant potential renewable electric generation resources, that renewable resources can have environmental advantages and can be inexhaustible, that an appropriate RPS can help stimulate development of such resources, and that renewable resources are complementary to other forms of generation in Illinois. Others, however, held the view that a mandatory RPS is not the proper vehicle to promote appropriate and cost-effective renewable resource development in accord with customer demands, that the claimed benefits of such resources are not a function of a mandatory standard, that many renewable resources are not dispatchable and can have excessive costs, and that an RPS may have an adverse effect on utility costs and resulting rates.

The RWG was, however, able to reach consensus that, if there were an RPS, qualifying renewable resources should specifically include existing and new renewable energy generating facilities (*e.g.*, landfill gas) that meet the definition of renewable energy resources in the Renewable Energy, Energy Efficiency, and Coal Resources Development Law of 1997 (20 ILCS 687/6-3). The RWG also reached consensus that, consistent with the consensus reached by the CIWG, utilities, full requirements suppliers acting on their behalf, and ARES may demonstrate compliance with such an RPS through ownership of renewable energy certificates issued by renewable energy generators that qualify per any Illinois standard.

The commodity component of each utility's rate designs should be based on the utility's costs of procuring and providing the commodity, including recoverable hedging costs, and differences between commodity charges should be based on differences in the commodity costs incurred to serve the load. Seasonal rates may be appropriate where the costs vary seasonally. The RWG also reached consensus that rate design and switching rules can impact the costs of commodity hedging and can have an impact on the competitive marketplace, and that the impact on the competitive marketplace and hedging costs should be considered when specifying rate design and switching rules.

As noted above, the RWG considered rates related to demand management, efficiency, and renewable resource programs. Other special rates and riders that previously have been used as incentives to modify electricity consumption based on costs associated with providing service to customers with special features such as load shape, facility type, and displacement of certain generation costs, are not mandatory parts of the rate structure for a utility offering standard offer service and/or default service going forward. The RWG also reached consensus that, during any restructuring of rates to accurately reflect the actual costs of providing delivery and customer services, the Commission should consider traditional rate design principles, such as reasonableness, rate continuity, avoidance of rate shock, customer equity, customer understanding, and reflecting fixed costs in fixed charges and variable costs in variable charges.

The RWG reached consensus that the Commission should not initiate rate proceedings for each electric utility prior to 2007. However, the RWG acknowledged the importance of orderly and timely implementation of post-transition changes in rates, and encourages utilities to

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file rates relating to the procurement Scenario(s) chosen on a timeframe that allows for orderly implementation of the Scenario(s) for customers, utilities, and the Commission. The RWG also encourages utilities and the Commission to coordinate schedules insofar as is possible.

The RWG did not reach consensus that any particular legislative amendments were required, and no specific amendments are proposed by the RWG. Similarly, the RWG did not reach consensus that any legislative change is required to accomplish any of the consensus recommendation or actions identified in this Report.

IV. Workshop Process

A. Description of the Group's Approach

Like its sister Groups, the RWG operated on a principal of consensus. Where consensus could be achieved on an issue, the Convenor reflected that consensus on a Progress Report sent to the Commission. Each such report was submitted to the Group in draft form prior to being sent to the Commission and all participants were given an opportunity to comment. Thus, while there was not substantive unanimity or even consensus on every issue, there was a unanimous consensus that each final Progress Report fairly reflected the consensus resolution reached at the meeting and, where a consensus resolution was not possible, fairly reflect the positions of the parties and the concerns that they felt were most critical.

At each RWG meeting, participants were reminded of the applicability of the Illinois Commerce Commission's traditional policy barring the subsequent use of non-consensus "[p]ositions taken, and documents and papers provided by the stakeholders in the Post 2006 Initiative Process … in any subsequent litigation, including administrative proceedings before the Illinois Commerce Commission, the Federal Energy Regulatory Commission, and other federal, state, or local governmental authorities." In addition, parties were reminded of the importance of strict compliance with all anti-trust laws and referred to the written Anti-Trust Guidelines for the Post 2006 Initiative prepared under the supervision of the ICC General Counsel, copies of which were available at the meeting.

To assist it in performing its work in an orderly manner, the RWG adopted several procedures:

- The RWG, in conjunction with the Procurement Working Group ("PWG") identified a set of twelve Procurement Scenarios that described, without prejudgment and in broad form, different appraoches that might govern the procurement of wholesale electricity by utilities on an individual or statewide basis. These Scenarios were used, where appropriate, to help analyze in an orderly manner RWG issues where the answer did or could change depending upon the method of procurement that was chosen.

- The RWG analyzed its Issues in topical groups or "Buckets." At its first plenary meeting, the RWG discussed ways of dividing the Issues assigned to it into Buckets that each contained topics with similar themes. A team of representatives was chosen to suggest a division, which was ultimately adopted by the RWG. This promoted coherent discussion of related issues and permitted parties with limited resources or interests to focus their participation. The seven Buckets were: (1) Unbundling; (2) Hedging of Electricity Procurement Costs; (3) Cost Recovery; (4) Competitive Interactions; (5) Demand Response, Efficiency, Renewables; (6) Other Rate Design Issues; and (7) Rate Setting Mechanisms. A list of the Issues assigned by the Commission to the RWG, showing the classification into each Bucket, is attached as Appendix IV-A.

- All RWG meetings were held in person, typically with a video link between Chicago and Springfield to permit live real-time participation in either city.

- Agendas and draft reports were circulated to the Group in advance to permit substantive preparation to occur before the meeting and to better allow stakeholders with focused interest to select which meeting to attend. Consensus items were reviewed by the RWG as a whole prior to being finalized.

B. Subgroups and Convenors:

1. No Subgroups were used by the RWG

2 Convenor - E. Glenn Rippie, Foley & Lardner LLP

V. Report of Results

This section reports the consensus and remaining non-consensus concerns relating to the each of the Issues assigned to the RWG by the original Post 2006 Initiative Issues List. It is organized by the topical "Buckets" used by the RWG to discuss and analyze these Issues. In each case, the substance of this Report follows that of Progress Reports that have been circulated among, reviewed by, and approved by the RWG, and then filed with the Commission. These Progress reports are also available on the Commission's web site (http://www.icc.state.il.us).

For ease of understanding, each Issue is repeated in *italics* before the corresponding discussion and consensus items.

A. Consensus Items Regarding Unbundling

31A) Should rates be determined, and shown on the tariff sheets, for both bundled and delivery services, as individual rate components, in a manner such as: customer charge, meter charge, distribution delivery charge, transmission delivery charge, and supply charge?

Consensus was reached that each utility, when filing bundled electric service tariffs to be effective after the expiration of the Mandatory Transition Period, should determine the cost of the commodity component of bundled rates (*e.g.*, the costs of procuring power and energy and related portfolio and risk management functions), and state the charge(s) for that component, separately from other components of bundled rates (*e.g.*, distribution, customer charge).

Consensus was reached that each utility, when filing bundled electric service tariffs and/or unbundled electric delivery services rates to be effective after the expiration of the Mandatory Transition Period, should determine and state the charge(s) for meter services that can be lawfully provided by a competitive Meter Services Provider separately from those for other delivery services.

The consensus that utilities should unbundle their bundled service prices in these two respects does not imply that additional price unbundling should not or may not occur, but rather that this level of price unbundling should occur at a minimum.

This consensus also reflects the general principle that where a service component of bundled rates is legally and practically able to be provided by a competitive supplier, there is a benefit to utilities unbundling the price of that service. A limitation on these principles is that commodity price unbundling may not be consistent with Scenarios 9 and 10 to the extent that they envision unchanged bundled rates. Unbundling of commodity prices also may be moot under Scenario 11, to the extent that utilities do not sell the commodity.

Issues concerning how FERC-jurisdictional transmission charges should be included in ICC-jurisdictional rates remain open and the RWG recognizes that how FERC rates should be incorporated may vary by Scenario and/or with the design of the FERC-jurisdictional rate in force in that utility's service territory.

Finally, several parties expressed concern that excessive price unbundling could pose risks of customer confusion, but this did not prevent the RWG from reaching consensus as stated above. Issues concerning bill formats were referred to the business processes portion of the CIWG.

31B) If so, should there be a single proceeding to reset the delivery component that would apply to both bundled rates and delivery service?

Consensus was reached that, in general, the delivery charges in the bundled and unbundled rates should be synchronized (*i.e.*, set based on the same test year and COS approach). However, while the RWG does not presume that such differences will exist, the Group notes that there may be legitimate cost-based differences in these charges to the extent that the range of delivery services consumed by shopping and non-shopping customers are legitimately different.

Consensus was also reached that, for each utility, there should be a single proceeding to set unbundled distribution rates and the distribution components of bundled rates. The Group did not address the question of when this proceeding should occur for each utility.

32) Should each utility have the same customer classes for both bundled and unbundled customers?

Consensus was reached that each utility should move toward synchronizing its bundled and unbundled customer classes.

The RWG recognizes three limitations on this principle. First, synchronization may not be possible or desirable where there are legitimate differences in the services, or in the costs of services, consumed by bundled and unbundled customers and where synchronization (because of these differences) would inappropriately group customers causing distinctive costs for the same service or inappropriately group customers receiving distinctive services. Second, special rate classes may be called for by energy assistance policies identified by the Energy Assistance Working Group, or to appropriately promote demand-side response, energy efficiency programs, or the use of renewable resources. Finally, third, where synchronization of classes would create inappropriate rate shock, a phased-in transition may be appropriate. (The Group did not achieve consensus as to when such phase-ins might be appropriate, with some participants believing that phase-ins are never appropriate for inter-class cost differences.)

B. Consensus Items Relating to Hedging of Electricity Acquisition Costs

34A) To what extent should non-competitive tariffed energy service offerings by utilities be hedged against fuel price/ market price risks?

The RWG reached consensus that, in principle, the costs of commodity acquisition, including the prudent and reasonable costs of associated hedging, should be included in the costs paid by the customers using utility commodity services.

The RWG reached consensus that, in principle, the degree of hedging appropriately undertaken by utilities, directly or through their commodity acquisition methods, may vary with the nature of the service being provided (*e.g.,* fixed price general service vs. RTP service) and with the broad customer group to which the service is being provided (*e.g.,* residential, C&I customers to whom the supply of power and energy has not been declared competitive, C&I customers to whom the supply of power and energy has been declared competitive).

1. What Portion of Load Should Be Hedged?

34B) Should utilities attempt to hedge for their full expected load serving obligation, or only for a portion?

The RWG reached consensus that utilities should at least partially hedge against variation in market prices included in the commodity portion of rates for residential and small commercial customers (as defined in the Act), either directly or through their commodity acquisition methods, in a manner appropriate given the procurement Scenario. The RWG does not intend that utilities be required to hedge fully against price changes, but reached consensus that utilities should not pass through a fully unhedged spot market price at least to residential and small commercial customers that are not taking service under a real time pricing rate. Consensus was not reached on whether utilities should pass through a fully unhedged spot market price to other non-residential customers that are not taking service under a real time pricing rate. The RWG also notes that the use of long-term contracts, or the use by vertically integrated utilities of generation they own, may or may not constitute an effective hedge; but did not reach consensus on a *per se* conclusion concerning the use of such assets as a hedge.

As also noted elsewhere, the RWG acknowledges that the ability to manage quantity and price risk is an important concern of larger non-residential customers as well, but did not reach consensus on the management of such risks by utilities.

The RWG reached consensus that, in general, as the degree of hedging reflected in the supply for a product declines, the rates for that product will tend to be more variable, with the extreme case being a real time pricing rate. Likewise, the RWG reached consensus that the reasonable and prudent level of hedging that is reflected in a rate will tend to vary with the length of the period over which the rate remains fixed and does not change to reflect changes in the cost of the commodity included in the service.

2. Over What Period(S) of Time Should Costs and Prices Be Hedged?

34C) For how long should prices be hedged?

See answer to Issue 33A

33A) Should rates be reset on a monthly or yearly basis or should rates be fixed for a multi-year period?

The RWG was unable to reach consensus as to the appropriate time period(s) during which non-RTP residential commodity prices should remain fixed, but did reach consensus that the period should be no less than one month (one bill cycle). The RWG notes that these periods relate to the commodity charges only; ICC-jurisdictional delivery charges should be reset under traditional rate case rules.

The RWG did not reach consensus as to whether large non-residential customers should be offered only RTP rates by utilities. However, the RWG did reach consensus that, if such rates are offered, the acceptable periods during which commodity prices in non-RTP non-residential rates should remain fixed should be no less than one month (one bill cycle). However, the RWG was unable to reach consensus as to whether it should be longer than one month. As with residential rates, the RWG notes that these periods relate to the commodity charges only; ICC-jurisdictional delivery charges should be reset under existing rate case rules.

Some participants were concerned that these consensus items might be viewed as calling for a change in existing law. The RWG does not intend that these consensus items necessarily require a change in existing law, or suggest that a change be made, because, for example, monthly true-up mechanisms and fuel clause type adjustments would be permitted under current law.

3. Should the Extent of Hedging Vary By Customer Type or Class?

33B) … [S]hould an assortment of these products [i.e., multiple periods] be made available?

The RWG was unable to reach consensus as to whether utilities should offer more than one rate option with different fixed-price periods to any given class of customers.

35) Should the type or extent of hedging be different for different classes of customers? For example, is the need for hedging less for customers who have greatest direct access to competitive markets?

The RWG reached consensus that residential customers should be offered a stably-priced commodity service (which could include, *e.g.*, seasonal rates or rates subject to true-up mechanisms) by utilities. The RWG acknowledges that the issue of price variability is important for non-residential customers as well, but did not reach consensus on whether a stably-priced commodity service should be offered to non-residential customers by utilities.

The RWG also reached consensus that, since residential and small commercial retail customers (as defined in the Act) as a class cannot practically manage their own quantity and price risk, those risks can and should be managed upstream by the utility and/or through its acquisition process. The RWG, however, recognizes that individual customers in these classes may elect to take service under a real time pricing rate. As also noted in response to Issue 34, the RWG acknowledges that the ability to manage quantity and price risk is an important concern of larger non-residential customers as well, but did not reach consensus on the management of such risks by utilities.

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The RWG reached consensus that, to the extent that utilities offer a stably-priced commodity service to customers, the price and quantity risks that arise from that offering should be managed at least in part by the utility, directly and/or through its acquisition process.

The RWG also reached consensus that, if utilities wish to hedge in order to reduce the variability in the price of a tariffed RTP service, they can propose such a tariff; but did not reach consensus as to whether utilities should be obligated to hedge price and cost risks associated with RTP services.

Some participants were concerned that these consensus items might be viewed as calling for a change in current law. The RWG does not intend that these consensus items necessarily require a change in existing law, or suggest that a change be made.

4. Recovery of Hedging Costs In Rates.

36) How should hedging costs be recovered in utility rates? How should prudence for hedging efforts and costs be assessed?

The RWG reached consensus that utilities should be able to recover from the customers receiving a hedged product the prudent and reasonable costs of the hedging. The RWG observed that, depending upon the method of supply procurement, hedging costs may be reflected in the cost of the resources procured from the market or may result from actions taken by the utility as portfolio manager.

The RWG reached consensus that unbundled customers who do not take commodity service from a utility may, in principle, be responsible for incremental utility commodity costs (understood to include capacity and commodity hedging costs), if any, caused by the exercise of an option to return to utility commodity service (*e.g.*, a "return fee"), if and when such customers elect to return. The RWG was unable to reach consensus as to whether unbundled customers who do not take commodity service from a utility may also be responsible for any incremental utility commodity costs incurred by reason of such customers' right to exercise an option to return (if one exists) prior to its exercise. However, the RWG was able to reach consensus that unbundled customers who do not take commodity service from a utility should not be responsible for utility commodity costs in any other circumstances.

The RWG also reached consensus that, if a procurement plan to manage price risk is within the scope of the Commission's authority to review and pre-approve, and is in fact reviewed in advance and approved by the Commission as prudent, the prudence of the plan should not be re-examined after the fact. However, pre-approval of a plan does not and cannot affect regulatory inquiry, under a prudence or justness and reasonableness standard, into whether or how the plan was followed, or whether it should be amended or terminated.

C. Consensus Items Relating to Cost Recovery Issues

1. Recovery of Basic Electricity Acquisition Costs

The RWG reached a number of consensus items. Many of these consensus items identify rate implications of specific procurement Scenarios. Those items are organized by Scenario and are described below under the heading "1. Scenario-specific consensus items". Other items that are not specific to particular Scenarios follow and are described below under the heading "2. Non Scenario-linked consensus items".

a. Scenario-Specific Consensus Items

38) How can the costs of providing tariffed non-competitive energy service best be recovered by utilities? Should rates simply be fixed at levels that are forecast to recover utility costs? Alternatively, should rates be based on a relatively current measure of market value and perhaps be reset frequently. Should new market value estimation methods be developed if rates are to be based on market indices? What, if any, are the uses for the Neutral Fact Finder processes in the post-2006 period?

The RWG acknowledges that rates, regardless of the procurement Scenario selected, must meet requirements of the law. For example, the RWG recognizes that rates must be just and reasonable. The RWG also recognizes that utilities are entitled to recover from customers their reasonable and prudent costs of procuring energy, as reflected in prior consensus items. The key issues posed by these Issues 38, 39, and 62 are: (a) whether and the degree to which utilities should accomplish recovery of commodity-related costs through a pass-through of procurement costs, and (b) the degree to which the utility remains at risk for commodity procurement risks. In addition, the RWG discussed whether a utility may be entitled to earn a return on its commodity-related investment, or should or should not receive a margin on providing commodity service. The RWG recognizes that the specific answers to these questions may vary with the procurement Scenario selected. By posing these questions, the RWG presumes no consensus as to their answers, except as stated below.

The RWG reached consensus that, under Scenarios 1 ("Full Requirements Auction") & 2 ("Full Requirements RFP"), utilities should pass through, with no "mark-ups" or "return on", the costs of the commodity itself. A regulatorily-approved price translation mechanism may be required to assign these costs among classes and rate components, particularly if the auction or RFP calls for potential suppliers to bid on average or nominal load shapes rather than to specify actual rate elements. The RWG reached consensus that if an auction or RFP structure is used for at least some customers as part of which a capacity-only auction is combined with real-time energy prices, then the energy component for those customers should be based upon hourly real-time prices that are passed through, and the capacity component should be derived from the auction results, assigned as described above. The RWG, however, reached no consensus on whether a capacity-only approach is appropriate. The RWG notes that true-ups may be appropriate or required for minor differences in, for example, the quantity of energy actually used by customers in different rate classes.

The RWG reached consensus that, under Scenario 3 ("Acquisition by Horizontal Tranche or Market Segment"), utilities' rates should include their costs of acquisition of the capacity and energy and the costs of hedging, if any. The RWG notes that this consensus item does not apply where a vertically integrated utility relies on owned generation resources without participating in the acquisition process (the RWG expresses no view in this consensus item on when this would be proper).

The RWG reached consensus that, under Scenario 4 ("Affiliate Purchases"), utilities' rates should include their costs of acquiring the capacity and energy and the costs of hedging, assuming that there is evidence, sufficient under law, that no affiliate abuse has occurred. The RWG notes that the Illinois Commerce Commission may retain jurisdiction to review rates including FERC-jurisdictional prices, as permitted by federal law, *e.g.*, under the "*Pike County*" doctrine. *(See Pike County Light & Power Co. v. Pennsylvania Public Utility Comm'n,* 465 A.2d 735 (Comm. Ct. of Pa. 1983)).

The RWG reached consensus that, under Scenario 5 ("Market- or Cost-Index Approach"), where the rates are based on an external benchmark, there is no role for post hoc regulatory review of the prudence of utilities' acquisition process, providing that the index has not been manipulated. The RWG notes that, in this Scenario, the price benchmarks must be correctly set and, as with other Scenarios, an appropriate mathematical translation may be required to determine individual charges and that the algorithm may be different depending upon whether the input prices are an index price for standard product or prices for a load shape. The RWG did not reach consensus as to the continuing need for traditional post hoc prudence review if there was a "safety valve" or other mechanism to change the benchmark after the fact. Finally, several parties noted that there may be concerns raised and addressed in the Procurement Working Group with the applicability of this Scenario and the resulting rates to small utilities and utilities that own generation facilities.

The RWG reached consensus that, in general, under Scenario 6 ("Integrated Resource Planning"), commodity acquisition costs should be recovered as in Scenario 3. Moreover, to the extent that the resource plan specifies particular commodity supply resources and the planning proceeding was properly vetted before the ICC with appropriate standards, compliance with the plan should preclude subsequent prudence review. However, pre-approval of a plan does not and cannot affect regulatory inquiry, under a prudence or just and reasonableness standard, into whether and how the plan is followed, or whether it should be amended or terminated. If the IRP process, after identifying a resource need, relies on the acquisition process from another Scenario as the means for procuring that resource, then the principles applicable to the other procurement mechanism in that other Scenario should be borrowed.

The RWG reached consensus that, under Scenario 7 ("Extension of the Transition Period"), utilities will recover their commodity costs, in whole or in part, through existing, frozen bundled rates and through other rates that include commodity components at charges found to be just and reasonable by the Commission.

The RWG observed that the essence of Scenario 8 ("No Changes") is that the Mandatory Transition Period expires without major legislative change and that each utility remains free, individually, to propose different acquisition processes and different methods of reflecting commodity costs in their rates (provided they are consistent with existing law), and that other parties involvement will tend to focus on these specific proposals instead of a more uniform process envisioned by other Scenarios. The RWG reached consensus that, regardless, the commodity component in rates under this Scenario should reflect the costs of acquisition (capacity, energy, and commodity-related risk management), with the same caveat as noted above that this consensus item does not apply to vertically integrated utilities that own generation facilities. The RWG also noted that, under this Scenario (without any implication with respect to any other Scenario), the capacity and energy cost components of rates may be subject to regulation under §16-111(i) of the Public Utilities Act.

The RWG reached consensus that, in general, under Scenario 9 ("Vertically Integrated Utility Supply"), utilities will recover production costs under traditional ratemaking principles or alternative regulation as allowed by law.

The RWG reached consensus that, in general, under Scenario 10 ("Re-Regulation of Electricity Production"), utilities will recover production costs under traditional ratemaking principles or alternative regulation as allowed by law.

The RWG reached consensus that, in general, under Scenario 11 (originally, the "Texas Model," subsequently revised before the PWG and renamed the "Market Responsive Pricing Model"), there may be no commodity costs for the utility *per se* to recover to the extent that it is generally relieved of the obligation and authority to provide retail bundled or unbundled commodity service. To the extent that utilities remain obligated to provide a standard offer commodity service, the commodity component of this service should be reflected in rates in the manner described above for the procurement Scenario used to secure the required resources.

The RWG discussed Scenario 12 (Renewables) where special rules apply to renewable energy generation or acquisition. The RWG reached consensus that, as a general rule, a voluntary green pricing rate should allocate any incremental cost of required resources to the "green pricing" customers, and not to other customers. The RWG also reached consensus that, if there is a general requirement to use renewable resources (*e.g.*, a Renewable Portfolio Standard), any incremental costs should be recoverable through rates, and if the requirement is applied equally to all suppliers, utility and competitive, such costs should be recovered through the commodity rate (assuming all suppliers have the obligation); however, the RWG did not reach consensus as to the means of full recovery if the renewable requirement only applies to utilities.

b. Non Scenario-Specific Consensus Items

The RWG reached consensus that traditional cost-of-service regulation should apply to generation directly owned by a utility, unless the utility or another party proposes an alternative regulatory approach with respect to such assets as permitted by law. The RWG did not reach any consensus that there should be any particular preferred alternative regulation mechanism.

The RWG reached consensus that there is no practical use for the NFF after 2006.

2. Hedging / Cost-Recovery Interface
Recovery of Hedging Costs In Rates

39) If rates were to be based on market indices, can current market value estimation methods be used or should another method be employed?

See answer to Issue 38.

40) If utilities are required or permitted to take actions to reduce price risk or the volatility of their costs, how should these costs be recovered?

The RWG notes that Issues 36 and 40 call for a reprise of much of the discussion reflected in the RWG's Hedging Issues consensus items. As stated in response to other Rates Working Group Issues, hedging costs should be recovered in utility rates as reflected in previous consensus items.

The means of judging the prudence and reasonableness of hedging costs will vary depending upon the Scenario. Moreover, the questions of if, when, and under what substantive standards the Commission may judge prudence will vary by Scenario.

For Scenarios that include advance supply purchases (*e.g.*, RFPs or auction plans) or explicit resource supply plans, if the Commission has ultimate authority to pre-approve a plan to manage risk, and if a plan to manage price risk is reviewed in advance and approved by the Commission as prudent, the prudence of the plan itself should not be re-examined after the fact. However, pre-approval of a plan does not and cannot affect regulatory inquiry, under a prudence or justness and reasonableness standard, into whether and how the plan was followed, or whether it should be amended or terminated.

Where it is appropriate for the Commission to assess prudence retrospectively, the Commission should apply traditionally-accepted prudence standards and rules of evidence. Where it is appropriate for the Commission to assess prudence prospectively or contemporaneously, the Commission should apply prudence standards to the process being used and the utilities' actions.

60) What level of reward (or opportunity) is appropriate for a distribution company who purchases "safety net" service for customers? What level of power procurement risk is appropriate for distribution companies?

While a question was raised concerning whether this Issue 60 also refers to Standard Offer Service, the RWG treated "safety net" service as referring to "default service," as that term has been used by the Utility Service Obligations Working Group, for the purpose of responding to this particular Issue only. The RWG reached consensus that utilities should be able to recover the variable and, if any, fixed costs associated with offering these services. The RWG did not reach consensus as to whether any additional reward is appropriate for offering these service, or whether the prices for these services should be set at levels designed to minimize the incentive of customers to continue to rely on them.

The RWG reached consensus that a single answer cannot be given to the questions of "*What level of power procurement risk is appropriate for distribution companies*?" The RWG refers to other consensus items concerning rate issues concerning hedging and to the discussions and consensus item of other Working Groups.

62) How should the cost of power to be included in rates be determined for those non-Integrated Distribution Company (IDC) utilities that continue to own generation? Should it be priced at company cost, at market rates, or on some other basis?

See answer to Issue 38.

D. Consensus Items Concerning Competitive Interaction

50) Should rates for customers who return to bundled service be different from the rates offered to basic bundled service customers? Do customers who move back and forth between bundled services and delivery services cause additional costs that should be charged only to those customers?

These questions each address rate treatment for customers switching to bundled service. The Utility Service Obligations WG has discussed the nature of the utility services available to migrating customers upon their return to utility commodity service in greater detail. The RWG will consider how the various Scenarios may affect the rate design of the various services that may be offered by utilities to such customers. [†]

The RWG reached consensus that, under Scenarios 1 and 2, if the switching and volume risk is priced into the RFP or auction bid and borne by the wholesale suppliers in an undifferentiated manner, then there is no need for commodity charges to customers returning to "bundled" service to differ from those applicable to customers who have never left "bundled" service. Moreover, under procurement Scenarios where the risks and costs of migration are built into the bid price in an undifferentiated manner, retail customers should be able to come to and go from the standard offer service (*i.e.*, the "bundled" rate applicable to their class). The RWG notes that the switching rules must be known by and consistent with the terms of the auction and/or RFP bids.

The RWG further reached consensus that other procurement Scenarios where the risks and costs of the migration of customers able to return to the standard offer service (*i.e.*, the "bundled" rate applicable to their class) are not built into undifferentiated supply bid prices (*e.g.*, vertical integration, an RFP with explicitly higher costs for intra-period returning customers, traditional cost-of-service models), they may include rates under which returning customers pay commodity charges reflecting the incremental cost, if any, of their return to utility commodity service. Those costs may be recovered by utilities from such customers through mechanisms which recover these incremental costs from such returning customers. A minimum stay period may also be utilized to mitigate the level of such incremental costs, which period may be coupled with a cost-based charge for early termination. Recovery of incremental commodity costs incurred by reason of the option to return, prior to the exercise of that right, is addressed in an earlier consensus item; as noted, the RWG did not reach consensus on whether such costs can properly be assigned to other customers.

51) Should customers returning to bundled service be put on time-based rates as their default option, under opt-out conditions?

See answer to Issue 50.

[†] The RWG is uncertain as to the meaning of the phrase "under opt-out conditions" included in Issue 51, and the author of the Issue was not available to the RWG for clarification. The RWG, however, believes that a reasonable response to the core issue can be provided jointly with Issue 50.

59) In the IDC model, the marketing of services by a distribution utility is significantly limited. How does this impact the offering of new rate structures or services, such as real-time pricing, which bring system benefits but which are unfamiliar to consumers and require education and marketing to be successful?

The RWG acknowledges that customer education is an important function and can contribute to bringing to customers benefits of services or structures which are unfamiliar to them, and understands that the law does and should allow an IDC to respond to customer inquiries concerning existing tariffed services. The IDC model envisions that other, non-utility providers will be central in the promotion of at least unfamiliar services involving the commodity, and restricts the ability of IDCs to market services and to solicit customers to use them. These issues are under detailed consideration by the CIWG. The RWG reached no separate consensus that any specific IDC rule revisions are required for ratemaking reasons and does not see this Issue as one which requires it to do so.

E. Consensus Items Related to Demand Response, Efficiency, Renewables

The RWG discussed the meaning of "Demand Response, Efficiency, and Renewables Issues," and identified several facets of each topic area. The RWG observed that: (a) demand response generally refers to the degree to which customer demand and usage (kW and kWh) responds and reacts to price and other signals, both under normal and emergency conditions; (b) efficiency generally refers to the efficient, economic, effective, and non-wasteful use of electricity by customers, the efficient use of generation resources in producing that electricity, and the efficient use of the transmission and distribution systems of utilities in delivering it, and (c) renewables generally refers to generating resources understood to use renewable sources of basic energy input. For reference, the Energy Information Administration ("EIA") website defines renewable resources as "naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time." The EIA identifies examples of such resources as including, without limitation: biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

1. Rates and Services

a. Demand Response, Efficiency, and Rate Design

54B) What kind of rate structures support efficiency? Time of Use rates for business and residential customer classes? Amending of declining block rate structures so that the first block of kWhs on a customer bill are the cheapest kWhs, and the additional kWhs are more expensive?

The RWG achieved consensus that, assuming that benefits exceed possible transaction and implementation costs, the efficient use of the commodity and, in general, of generating and delivery resources as a whole is supported by the availability of rates for businesses and residential customers that reflect hourly real-time prices, ideally locationally. The RWG did not reach consensus as to whether hourly pricing rates must be offered by utilities to residential customers. The RWG did reach consensus that, if such rates are offered to residential customers or to non-residential customers prior to a declaration of competitiveness for such customers or the abandonment of other rates to such customers, they should be offered to such customers as optional rates, with the following caveats. There was no consensus as to whether hourly pricing rates should be optional for customers for whom hourly pricing rates are not currently optional under existing tariff, law, or regulation or for nonresidential customers that require standby or interim supply service. The RWG also did not reach consensus as to whether such rates should also be optional for non-residential customers after a declaration of competitiveness or the abandonment of other rates.

The RWG reached consensus that properly-designed interruptible, curtailable, and direct load control programs can promote efficiency of use by customers and can aid in optimizing the generation and delivery systems. The RWG reached further consensus that, depending upon the generating portfolio and the procurement Scenario used, and the load characteristics of a utility, rate blocks, whether declining or increasing, can have a material effect on optimizing system efficiency. While there was consensus (as stated above) as to the importance and effect of these programs, the RWG did not reach consensus as to whether utilities, in particular, should be the entities required to or prohibited from offering each such type of service. But, the RWG did reach consensus that utilities should not prohibit or unreasonably impede retail customers from participating in RTO programs for which they are otherwise eligible.

66) Should incentives be put in place to encourage consumers to make their demands more price-responsive? What form might such incentives take?

The time of use (*e.g.*, on-peak / off-peak) and other pricing structures discussed above in response to Issue 54B should provide sufficient incentive to encourage consumers to make energy demands more price-responsive. The competitive marketplace (Load Serving Entities and Curtailment Service Providers) and RTOs may provide other types of incentives to encourage consumers to make energy demands more price responsive.

b. Real-Time and Time-of-Use Rates.

55) Should there be an interruptible rate option for transmission and distribution services and/or generation services? How should such a rate be designed?

The RWG's consensus with respect to interruptible rate options for generation services is reflected in response to Issues 54B and 66. Utilities should be able to implement and utilize voluntary programs to reduce end use customer load to address constraints on the transmission or the utility's distribution systems. The RWG does not intend these programs to prejudice customer participation in RTO programs for which they are otherwise eligible.

58) Should existing real-time tariffs be modified to encourage customer interest in such tariffs? If so, what modifications are necessary?

The RWG reached consensus that existing non-residential Real-Time Pricing tariffs should, if necessary, be modified effective after the end of the Mandatory Transition Period ("MTP") to reflect the cost of service, no later than as part of the utility's first general rate case proposing rates to be effective after the end of the MTP. The RWG reached consensus that Real-Time Pricing rates may also otherwise be modified to implement improvements, but did not reach consensus that modifications are required.

63) Which types of time-based rates, ranging from TOU to Critical Peak Pricing to Day Ahead Real Time, are appropriate for which customer classes? What has customer acceptance of such been in Illinois and other states to date?

See responses to Issues 54 and 55.

64A) To what extent is existing infrastructure a barrier to wider deployment of time-based rates?

The absence of the installation of interval meters at many customer locations is not conducive to wider deployment of at least hourly time-based rates. However, the cost of eliminating this impediment for all customers, including with respect to the meters themselves as well as addressing data processing, billing, and customer care issues, would have to be addressed. But, the RWG was not in a position to evaluate the net benefits of specific installations during this process.

c. New Rates or Services

54A) What new rates or services, if any, should utilities offer (e.g., green power options)?

The RWG did not reach consensus as to whether utilities should be required to offer any new service, and did not reach consensus as to whether utilities should be permitted to offer new commodity services.

2. Cost Recovery

52) How should costs related to energy efficiency and demand reduction be charged in rates?

The change (whether in net costs, or net savings), if any, in commodity acquisition expense to the utility as a result of energy efficiency and demand reduction programs (*e.g.*, voluntary load reduction programs, or direct load control programs) should be fully included in the utility's commodity rates. The net change in costs (whether an increase or decrease) of such programs in the utility's delivery expense or investment should be included in its delivery charges, and allocated to facility, customer and/or meter-related charges as appropriate. The RWG did not reach consensus as to the particular rate design appropriate for any particular program.

53) How should costs for obtaining renewable energy be charged in rates?

See the discussion of Scenario 12 in response to Issues 38, 39, and 62.

64B) … How can electricity providers be provided with cost recovery assurances and incentives that will lead to the necessary infrastructure being put in place [for time based rates]?

See response to Issue 52 with respect to providing utilities with recovery of costs. The RWG could not reach consensus, in the absence of a reference to a particular program, as to whether or not any additional incentives are required or, if so, what they should be.

3. Renewable Portfolio Standard

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94) Should the State mandate a renewable portfolio standard ("RPS") as part utilities' post-2006 energy procurement process?†

95) If so, what types of resources (e.g., wind, biomass, solar, waste burning, landfill gas) should qualify as renewable resources for the purposes of the RPS?†

96) If so, at what level(s) should the standard be set? Should is specify a particular quantity of renewable resources or express the standard as a percentage of the LSEs load? Should the standard be defined in terms of aggregate MWhs used or MWs of capacity? †

The RWG reached consensus that the question of whether a renewable portfolio standard ("RPS") should be mandated by Illinois after the end of the Mandatory Transition Period is an important issue to be addressed. While there was disagreement among members of the RWG on whether an RPS should be mandated by the State of Illinois and on whether other alternatives for stimulating cost-effective renewable resource development (*e.g.*, green rates) should be adopted, the RWG reached consensus that there are important considerations that must be reflected in a workable RPS, if one is mandated:

- Any RPS must be aligned with the post-2006 procurement process and facilitate the acquisition of cost-effective renewable energy.
- Any RPS must be competitively neutral and consistent with the consensus on RPS issues reached by the Competitive Issues Working Group.
- Any RPS must address cost recovery consistent with the consensus reached in the Rates Working Group.
- Any RPS must consider the effect of the use of renewable resources on rates.

The RWG does not intend to suggest that these are the only considerations in adopting an RPS, nor (as noted above) was there consensus that any RPS should be implemented. Although the discussion enabled the RWG to reach consensus on some items, two views remained: one in support of an RPS that addresses the concerns identified herein and one in opposition to an RPS.

Under the first view members of the Group in support stated that a renewable portfolio standard should be adopted by the State, provided that certain conditions were met. These members expressed the view that, on the benefits side, considerations favoring an RPS include a recognition that Illinois has significant potential renewable electric generation resources, especially from wind energy. Renewable electricity generation is a clean, non-polluting and, in many cases, inexhaustible energy source. Increased use of renewable electricity generation holds the potential to enable Illinois to reduce or moderate the increase in consumption of traditional fossil fuels and emissions of criteria pollutants (i.e., NOx, SOx, VOCs, and particulates) from burning these fuels by reducing reliance on generation from those sources, diversify Illinois' energy portfolio by helping to reduce fuel price risk, reduce carbon emissions and consequent global warming, reduce mercury emitted from coal-fired plants, and help contribute to national security through increased energy independence. To the extent that the resource is located in Illinois, renewable generation such as wind can also bring economic

† These new Issues were assigned to the RWG by Cmr. O'Connell-Diaz and the Convenors.

development and tax base enhancement to rural areas. Renewable energy resources are complementary to other forms of generation in Illinois.

In addition, these members noted that implementation of an RPS would stimulate the development of renewable energy resources by creating demand. As a factual matter, the RWG also noted that sixteen states have an RPS, including California, New York, and Texas.

Under the second view members of the RWG in opposition stated that a mandatory portfolio standard is not the proper vehicle to promote appropriate and cost-effective renewables development in accord with the demands of Illinois customers using the energy. They noted that many renewables are not dispatchable and may have excessive costs, and also noted that the claimed benefits are not a function of a mandatory standard. These parties stated an RPS would have an adverse effect on utility costs and resulting rates. In addition, some members stated that the State of Illinois is not the right party to be adopting an RPS, were one to be adopted, but that a national standard would be more appropriate.

> *95) If so, what types of resources (e.g., wind, biomass, solar, waste burning, landfill gas) should qualify as renewable resources for the purposes of the RPS?*

If an RPS is mandated, it should include a broad definition of the types of resources that qualify as renewable resources in order to ensure that a cost-effective range of renewable resources is developed and secured for Illinois consumers.

The definition of qualifying renewable resources should specifically include existing and new renewable energy generating facilities (*e.g.*, landfill gas) that meet the definition of renewable energy resources in the Renewable Energy, Energy Efficiency, and Coal Resources Development Law of 1997 (20 ILCS 687/6-3):

> As used in this Law, "renewable energy resources" includes energy from wind, solar thermal energy, photovoltaic cells and panels, dedicated crops grown for energy production and organic waste biomass, hydropower that does not involve new construction or significant expansion of hydropower dams, and other such alternative sources of environmentally preferable energy. "Renewable energy resources" does not include, however, energy from the incineration, burning or heating of waste wood, tires, garbage, general household, institutional and commercial waste, industrial lunchroom or office waste, landscape waste, or construction or demolition debris.

The RWG does not intend by this consensus definition to exclude on-site generation facilities, using renewable technologies that result in tradable renewable energy credits.

Finally, there was a discussion among members of the RWG as to whether renewable resources should be limited to Illinois-only resources. The RWG notes that the definition of renewable energy resources in this law is not limited to resources in Illinois.

96) If so, at what level(s) should the standard be set? Should it specify a particular quantity of renewable resources or express the standard as a percentage of the energy supplier's load? Should the standard be defined in terms of aggregate MWhs used or MWs of capacity?

Consistent with the consensus reached by the Competitive Issues Working Group, the RWG reached consensus that utilities, full requirements suppliers acting on their behalf, and (A)RESs may demonstrate compliance with an RPS through ownership of renewable energy certificates issued by renewable energy generators that qualify per any RPS standard in Illinois.

Finally, the RWG acknowledged that the Illinois legislature has already approved renewable energy goals of 5% of energy production and use by 2010 and 15% by 2020 in the Illinois Resource Development and Energy Security Act, 20 ILCS 688/5(f). However, there was no consensus among the RWG that these goals constitute proper standards for a RPS, should one be adopted.

As noted in response to Issue 94, there were two divergent views on whether an RPS should be mandated by the State of Illinois. Therefore, agreement could not be reached on the level of any such standard. However, participants supporting or accepting an RPS note that they can be designed to work on either a MWh or MW basis, or on the basis of MWh's derived from installed capacity, and agreed that initial year targets should be reasonably achievable, and modest, but consistent with the purpose of promoting the development of additional renewable energy resources, and phased in to higher levels over time to achieve the specified levels while, at the same time, modulating any effect of higher electricity costs for consumers. The RWG did not reach consensus as to whether an RPS should be based on a percentage of electricity consumed (MWh), an installed capacity basis (MW), or any other standard. Other parties opposed to an RPS suggested that establishing a standard of any kind was inappropriate and that a standard based on percentage of electricity consumed was particularly objectionable because in some instance renewables had a low capacity factor and required the installation of additional generation to back them up.

4. Other Issues

56) Should utilities be required to demonstrate consideration of energy efficiency, demand reduction, and distributed generation strategies as part of any proposal for new distribution and/or transmission facilities?

The RWG understands that this Issue refers to proposals for new distribution and/or transmission facilities that currently require Commission approval (*e.g.*, require Certification or authorization to use eminent domain). The RWG understands that present standards for such approvals include consideration of appropriate energy efficiency, demand reduction, and/or distributed generation resources. The RWG reached further consensus that all stakeholders should promote the consideration of appropriate energy efficiency, demand reduction, and distributed generation resources as part of the RTO transmission planning process. However, the RWG does not by this mean to imply that utilities should or should not themselves construct distributed generation facilities.

61) Should Integrated Distribution Company (IDC) rules be changed to provide the option to promote green power, real-time pricing tariffs, curtailable rate options, etc..., by the distribution company?

See response to Issue 59.

F. Consensus Items re Other Rate Design Issues

1. Production / Commodity Cost Recovery and Rate Design

41) Rate design issues can also have significant competitive implications. Unless rates are designed to send correct price signals, economically efficient consumption decisions and economically efficient competition will not necessarily result. How can decisions about the method of recovery of production costs and the allocation of those costs among rates and customers be made in a manner likely to promote efficiency, and efficient competition between providers and resources?

Consensus was reached that the commodity component of each utility's rate design should be based on the utility's costs of procuring and providing the required production resources and that differences between commodity charges should be based on differences in the cost of supply resources required to serve the load. The RWG expressly recognized that charges may vary for rate options requiring different types of generation resources or special pricing (*e.g.*, RTP rates, a "green power" rate or portfolio requirement).

The RWG recognizes three limitations on this principle. First, cost-based generation rate designs may be phased-in, if and where inappropriate rate shock would otherwise result. (The Group did not achieve consensus as to when such phase-ins might be appropriate, with some participants believing that phase-ins are never appropriate for inter-class cost differences.) Second, special generation rate designs may be called for by energy assistance policies identified by the Energy Assistance Working Group, or to appropriately promote demand-side response, energy efficiency, or the use of renewable resources. Finally, the policy favoring cost-based rate designs should not be viewed as barring or limiting authorized alternative regulation plans.

The RWG reached consensus that production costs, for this purpose, include the costs of generation, the costs of purchased power, and costs of providing purchased power. The production costs, so defined, should be allocated based on the cost of providing the production service. To the extent that these functions are provided by utility assets in Rate Base, the RWG acknowledged that a utility can earn a return of and on Rate Base.

42) Should the cost of power be determined as a fixed amount in base rates from rate case to rate case?

This mechanism applies most plainly to those Scenarios where production costs are necessarily determined in a traditional rate case (*e.g.,* Scenarios 9 & 10), as opposed to Scenarios that utilize a formula approach (*e.g.,* Scenarios 1 – 3) or a fuel cost adjustment mechanism. The RWG understands that the Commission has the legal authority to establish, in a rate case, the production components of retail energy rates at a lawful and just and reasonable level regardless

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of the Scenario chosen, but did not reach a consensus as to if, or under what circumstances, such components should be fixed.

2. Switching Rules and Hedging Costs

37) To what extent can rate design and switching rules reduce the costs of hedging? What are the implications for such changes on the competitive retail marketplace?

The RWG reached consensus that rate design and switching rules can impact the costs of commodity hedging. However, it is impossible to determine the extent of that impact, absent knowledge of the procurement Scenario being followed by the utility, and of the specific rate design and switching rules proposed. The RWG reached consensus, however, that rate design and switching rules can have an impact on the competitive marketplace, and that the impact on the competitive marketplace and hedging costs should be considered when specifying rate design and switching rules.

3. Delivery Cost Recovery and Rate Design

48) Should charges be restructured to more accurately reflect the costs of providing delivery and customer services that do not vary significantly based on the kilowatt-hours consumed (e.g., standby service rates)?

The RWG reached consensus that, during any restructuring of rates to accurately reflect the actual costs of providing delivery and customer services, the Commission should consider traditional rate design principles, such as reasonableness, rate continuity, avoidance of rate shock, customer equity, customer understanding, and reflecting fixed costs in fixed charges and variable costs in variable charges.

4. Other Rate Design Issues

49) Should some or all rates for some or all of the rate classes be determined on a seasonal basis?

The RWG reached consensus that seasonal rates may be appropriate, where the costs are found to vary seasonally.

5. "Special" Rates

47) Should "special rates" (e.g., space heating, lighting) be maintained?

The RWG addressed the need for, and appropriateness of, rates related to demand management, efficiency, and renewable resource programs in response to the Demand Management, Efficiency, and Renewable Resource Issues (*i.e.*, Issues no. 52 – 56, 58, 61, 63, 64, and 66). Other special rates and riders that previously have been used as incentives to modify electricity consumption based on costs associated with providing service to customers with special features such as load shape, facility type, and displacement of certain generation costs, are not mandatory parts of the rate structure for a utility offering standard offer service and/or default service going forward. However, rate and pricing structures that properly reflect cost causation and equitable cost recovery principles, along with other traditional rate design principles identified in response to Issue 48, should be considered when addressing loads that have been eligible for service under such special rates.

93) Is there a role for economic development "rates" in a post-transition marketplace? If so, should tariffed non-competitive energy services offered by utilities be the vehicle, or can the State implement economic development programs through the competitive sector as well?†

The RWG acknowledges the importance of economic development to Illinois. Cost-based economic development rates may be offered by utilities procuring power and energy under procurement Scenarios 9 and 10. Otherwise, except for contracts or delivery service rate components that are cost-based or that address uneconomic bypass, new economic development contracts or rates should not be offered by utilities in a post-transition marketplace. The RWG does not intend by this recommendation to suggest that existing contracts under existing economic development rates should be abrogated.

6. Alternative Regulation

65) Should the requirements related to approval of alternative regulation plans be revisited with a goal of setting forth more realistic requirements so such plans could actually be implemented?

The RWG reached consensus that requirements related to the approval of alternative regulation plans should not be revisited as part of the post-2006 transition process.

46) Can or should rates be restructured to eliminate inter and intra-class subsidies in existing bundled rates?

The RWG was unable to reach consensus on a single answer to this question. However, RWG participants believe that the answer to this question is either: (a) yes, or (b) that moving toward elimination of inter- and intra-class subsidies in pre-2007 bundled rates is one goal that can be considered along with other ratemaking goals, such as those identified in response to Issue 48, with respect to delivery and customer service components.

G. Consensus Items Relating to Rate Setting Mechanisms

1. Future rate Cases

30) Should the Commission initiate rate proceedings for each electric utility prior to 2007?

No. However, the RWG encourages utilities and the Commission to coordinate schedules insofar as is possible, and encourages utilities to file rates relating to the procurement Scenario(s) chosen on a timeframe that allows for orderly implementation of the Scenario(s) for customers, utilities, and the Commission.

2. Fixed v. Formula Rates

43) Should some or all customer rates reflect market indices? How would costs be recovered if some rates were to reflect market indices? Should new market value

† This Issue was transferred to the RWG from the EAWG.

estimation methods be developed if rates are to be based on market indices? What are the uses, if any, for the Neutral Fact Finder processes in the post-2006 period?

The RWG reached the following consensus if this Issue is understood to refer to the use of an index to set a basic cost of electricity as part of a procurement Scenario. With this understanding, whether the commodity component of non-RTP customer rates (other than the PPO, as required by law) should utilize a market index is dependent upon whether the procurement Scenario uses such an index. With respect to cost recovery, the RWG refers to its responses to the Cost Recovery Issues (*i.e.*, Issues no. 36, 38 – 40, 60, and 62). The portion of this Issue concerning the NFF has already been answered specifically as part of the response to Issue 38.

44) Should Ill. Adm. Code 425 be modified to reflect the "new" more significant role of purchased power in energy costs? (May also be in cost recovery)

45) Should 83 Ill. Adm. Code 425 be modified to address demand costs, transmission costs, interest, and reinstatement of a fuel adjustment clause after the end of the mandatory transition period? Should the Commission develop rules for a new power purchase clause? Should a separate transmission charge (perhaps a rider) be considered? (As opposed to transmission being included as part of a fuel adjustment clause)

The RWG cannot definitively answer Issues 44 and 45 without reference to a specific procurement Scenario and, possibly, an understanding of how that Scenario is to be implemented. However, 83 Illinois Administrative Code Part 425 should not be modified to address demand costs, transmission costs, interest, and reinstatement options, as noted in this Issue, unless it is found to be inconsistent with any of the procurement Scenario(s) ultimately approved by the Commission or to prohibit the recovery of transmission costs through a rider or similar tariff mechanism.

57) What are the circumstances under which PPO must be offered subsequent to the end of the mandatory transition period? How should Sec. 16-110 provisions be implemented by the utilities that are required to offer PPO service after 2006?

The circumstances under which the Power Purchase Option ("PPO") must be offered subsequent to the end of the mandatory transition period are governed by Section 16-110(c) and (d) of the Act. As the RWG understands it, the PPO available under Section 16-110(c) of the Act is limited to non-residential customers whose service has not been declared competitive and who paid any transition charges that such customers were legally obligated to pay. The PPO available under Section 16-110(d) of the Act is further limited to exclude small commercial customers, as that term is defined in the Act.

The RWG reached consensus that the post-transition PPO, as described above, should be reflected in new or revised PPO rates to be filed by utilities that have collected any transition charges from customers permitted to purchase power and energy under such rates, and that such rates should be filed so as to be effective prior to any notice period required of such eligible customers. Presuming that the market value determined under Section 16-112 is a function of the power procurement Scenario adopted by the utility, the form of these PPO rates should be consistent with procurement Scenario selected.

VI. New or Unanswered Questions

A. Unanswered Questions

What level of power procurement risk is appropriate for distribution companies? This issue was functionally addressed by the PWG.

B. New Questions

Issues 94, 95, and 96 were identified and assigned to the RWG during the process.

C. Questions Deferred to Other Groups

The issue of bill formats was referred to the business process sub-Group of the CIWG.

VII. Other Documents and Attachments

A. Agendas

The following documents and items can be found on the Internet at the Illinois Commerce Commission's web site (http://www.icc.state.il.us) on the Post-2006 Initiative home page (http://www.icc.state.il.us/ec/ecPost.aspx). Copies of the Agendas are also attached collectively as Appendix VII-A.

1. May 21, 2004
2. June 1, 2004
3. June 8, 2004
4. June 15, 2004
5. June 22, 2004 (Joint Meeting)
6. June 23, 2004 (Joint Meeting)
7. June 29, 2004
8. July 13, 2004
9. July 20, 2004 (Joint Meeting)
10. July 27, 2004
11. August 3, 2004
12. August 10, 2004
13. August 18, 2004

B. Progress Reports

The following documents and items can be found on the Internet at the Illinois Commerce Commission's web site (http://www.icc.state.il.us) on the Post-2006 Initiative home page (http://www.icc.state.il.us/ec/ecPost.aspx). Copies of the Progress Reports are also attached collectively as Appendix VII-B.

1. May 21, 2004
2. June 1, 2004
3. June 8, 2004
4. June 15, 2004
5. June 22-23, 2004
6. June 29, 2004
7. July 13, 2004
8. July 20, 2004
9. July 27, 2004
10. August 3, 2004
11. August 10, 2004
12. August 18, 2004

C. Summaries of Joint Sessions

The RWG participated in three joint session with the PWG and the CIWG. Summaries of these meetings follows. The agendas for each of these three meetings, and the materials distributed by the presenters at each are attached hereto, respectively, as Appendices VII-C-1, VII-C-2, and VII-C-3.

- On June 22, 2004, the Groups jointly met to hear presentations concerning the organization, structure, function, and operation of the RTOs that include portions of Illinois, *i.e.*, PJM and MISO. The meeting began with a detailed presentation by Dr. John Chandley of LECG about the operation of RTOs, their transmission and market tariffs, and how real-time and locational marginal price (LMP) electric markets function. Presentations concerning PJM structure, operation, and services were made by Richard Mathias, Stu Bressler, and Jeff Bladen. Presentations concerning MISO structure, operation, and services were made by Roy Jones, Richard Doying, and Dr. Ron McNamara. The presenters each responded to questions from participants.

- June 23, 2004, the Groups jointly met to hear presentations concerning post-transition efforts of other states and the United Kingdom. Presentations were made regarding: the new California models by William Chen (Constellation NewEnergy), the east coast models by Michael Brosius (Morgan Stanley, principally NJ and MD) and Tom Bessette (Constellation NewEnergy, principally MA and ME), the UK model by John Domagalski (Ernst & Young), and the Texas model by Jess Totten (Texas PUC). The presenters each responded to questions from participants.

- July 20, 2004, the Groups jointly met to hear presentations concerning the performance of markets in the PJM and the MISO operating areas, and Illinois in particular, as well as the authority and ability of the Federal Energy Regulatory Commission's Office of Market Oversight and Investigations ("OMOI") and the Market Monitoring Units of PJM and the MISO to detect, deter, and respond to possible market manipulation or other improper market conduct. Presentations were made by Stephen Harvey (Deputy Director, OMOI, FERC), Joseph Bowring (Market Monitor, PJM), and Dr. David Patton (Market Monitor, MISO). The presenters responded to questions from participants.

D. List of Presentations and Presenters

No live presentations were made, except as identified above.

E. Presentations

No live presentations were made, except at the three joint sessions identified above.

The materials used at the three joint session described above are available on the Internet at the Illinois Commerce Commission's web site (http://www.icc.state.il.us) on the Post-2006 Initiative home page (http://www.icc.state.il.us/ec/ecPost.aspx), and are, as noted above, also attached hereto as Appendices VII-C-1, VII-C-2, and VII-C-3.

Materials describing the PJM Demand-Response Programs provided by Exelon Energy Delivery and DCEO are available on the Internet at the ICC's web site (http://www.icc.state.il.us) on the Post-2006 Initiative home page (http://www.icc.state.il.us/ec/ecPost.aspx) were made available to the RWG. This presentations, authored by Exelon and PJM, are also attached hereto as Appendix VII-E-1.

Finally, materials supporting the position and proposal of the Coalition of Energy Suppliers on certain rate design issues were distributed to the RWG and discussed at the August 10, 2004 meeting of the Group. These material are attached hereto as Appendix VII-E-2.

F. Subgroup Reports and Materials

No subgroups were used by the Rates Working Group.